RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three months ended March 31, 2011 to the three months ended March 31, 2010.

Revenues

Three months ended March 31 (Canadian dollars in millions)	2011	2010	$ Change	% Change
Transmission	351	320	31	10
Distribution	1,093	983	110	11
Other	16	16	-	-
	1,460	1,319	141	11
Average Ontario 60-minute peak demand (MW)[1]	21,757	20,935	822	4
Distribution - units distributed to customers (TWh)[1]	8.3	8.0	0.3	4

[1] System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and therefore our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenue associated with transmitting excess generation to surrounding markets and ancillary revenues which are primarily attributable to maintenance services primarily provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $31 million, or 10%, compared to the same period in 2010. This increase was primarily due to higher revenues of $22 million resulting from a recent Ontario Energy Board (OEB) decision. On December 23, 2010, the OEB rendered its decision on the 2011 and 2012 transmission rate application for our subsidiary, Hydro One Networks Inc. (Hydro One Networks). The decision followed extensive oral and written reviews of evidence we submitted for the funding necessary to support our system requirements. The resulting revenue requirement was approved effective January 1, 2011 and will support investments to address our aging critical infrastructure, supply mix objectives for generation including off-coal initiatives, and the initiation of investments in support of the Green Energy Act (GEA).

Also contributing to increased revenue was the higher average monthly peak demand experienced during the first quarter. The average annual Ontario 60-minute peak demand was 822 MW higher than last year, resulting in higher revenues of $12 million. Weather was generally colder over the winter months when compared to the same period last year.

These transmission tariff revenue increases were partially offset by lower ancillary revenues of approximately $3 million resulting from the December 23, 2010 OEB decision.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Our distribution revenues increased by $110 million, or 11%, in the first quarter of 2011 compared to the same period last year, including an increase in the recovery of higher purchased power costs of $64 million, as described below in the section "Purchased Power."

Increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks. On April 9, 2010, the OEB approved new tariff rates effective May 1, 2010. On December 21, 2010, the OEB approved new tariff rates for Hydro One Networks effective January 1, 2011. Both OEB decisions followed extensive written and oral reviews of the evidence we submitted for the maintenance and investment requirements of our distribution system, including those necessary to support renewable distributed generation. The combined impact of these decisions was a $47 million increase in distribution revenues compared to the same period last year. These tariff rate increases enable the safe and reliable delivery of electricity to our customers throughout Ontario. The development of the Smart Grid is necessary to ensure the future of our system by facilitating the connection of new generation. Also contributing to increased revenues was higher energy consumption resulting primarily from the colder winter. This higher consumption resulted in an increase in distribution revenue of $6 million compared to the first quarter last year.

These increases were partially offset by a revenue reduction of $6 million over last year associated with the cessation of recovery of a distribution-related regulatory account effective April 30, 2010. We also experienced lower ancillary revenues of approximately $1 million compared to the prior year.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both of which are adjusted twice annually. We began transitioning our RPP customers to time-of-use billing May 1, 2010 and the vast majority of our RPP customers are anticipated to be on time-of-use billing by the end of June 2011. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP for the reporting and comparative periods is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5
November 1, 2010	1,000	750	6.4	7.4

	Time-of-Use Rates (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
May 1, 2010	9.9	8.0	5.3
November 1, 2010	9.9	8.1	5.1

Our purchased power costs increased by $64 million, or 10%, to $719 million compared to the same period last year. This increase in our purchased power costs was primarily due to the impact of changes in the OEB's two-tiered RPP rate for residential and other eligible customers of $22 million, higher demand for electricity of $22 million, higher purchased power costs for customers that are not eligible for the RPP of $10 million, higher transmission charges of $7 million due to the OEB's transmission rate decision effective January 1, 2011, and changes in the OEB's time-of-use RPP rate for residential and other eligible smart meter customers of $4 million. The effect of these increases was partially offset by lower wholesale market service charges levied by the IESO of $1 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Three months ended March 31 (Canadian dollars in millions)	2011	2010	$ Change	% Change
Transmission	106	107	(1)	(1)
Distribution	142	137	5	4
Other	14	14	-	-
	262	258	4	2

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $1 million, or 1%, in the first quarter compared to the same period of the prior year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were higher by $3 million. These increases were primarily attributable to higher requirements for demand corrective station maintenance for power equipment, higher forestry program expenditures primarily as resources were utilized to advance the program due to favourable weather conditions, and an increased focus on addressing our expanded environmental on-site oil leak reduction program consistent with our priority on environmental stewardship. Expenditures in support of the transmission system declined by $4 million, mainly reflecting lower information technology requirements.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $5 million, or 4%, in the first quarter compared to the same period of the prior year. Expenditures in support of our distribution system increased by $6 million, primarily reflecting higher costs required to support customer operations, partially offset by lower information technology requirements. Our work programs expenditures were lower by $1 million than last year with lower forestry expenditures due to a temporary re-direction of work, partially offset by higher line maintenance requirements due to a higher volume of trouble calls.

Depreciation and Amortization

Depreciation and amortization expense for the first three months of the year reflects an increase of $5 million, or 4%, to $144 million compared to the first quarter of last year. This was mainly attributable to an increase of $8 million resulting from our placement of new assets in service, consistent with our ongoing capital work program. A further increase of $2 million was the result of increased fixed asset removals associated with our capital projects. Amortization of regulatory and other assets decreased by $5 million, mainly due to the completion of the amortization of a distribution regulatory account during the second quarter of last year.

Financing Charges

Financing charges decreased by $1 million, or 1%, to $84 million in the first quarter compared to the same period last year. The decrease is primarily due to higher capitalized interest of $2 million associated with higher levels of construction-in-progress and higher other income of $2 million related to our long-term investment. These reductions in our financing charges were partially offset by an increase of $3 million associated with a higher average level of debt, partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased from $13 million, to $39 million in the first quarter compared to the same period last year. The increase was primarily due to higher pre-tax income in the quarter and increased net temporary differences including those related to capital cost allowance versus depreciation on our fixed assets and capitalized interest, partially offset by a reduction in the statutory tax rate from 31.00% to 28.25%.

Net Income

Net income of $212 million was higher by $43 million, or 25%, compared to the same period in 2010. Net income reflected two OEB-approved distribution rate decisions and a transmission rate decision. The decisions include a return on equity on new assets coming in-service over the last few years as well as a higher rate of return for our Transmission Business. The

transmission rate decision supports investments to address our aging critical infrastructure, the supply mix objectives for generation including off-coal initiatives, and the initiation of investments in support of the GEA.

The two distribution rate decisions support the maintenance and investment requirements of the distribution system, including those to support renewable distributed generation and enable the safe and reliable delivery of electricity to our customers throughout Ontario. A smarter grid for distribution will further facilitate investment in renewable sources of power generation, providing clean energy sources and decreasing reliance on carbon-based fuels.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from June 30, 2009 through March 31, 2011. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	**2011**		**2010**				**2009**	
Quarter ended	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**
Total revenue[1]	1,460	1,280	1,360	1,165	1,319	1,207	1,144	1,090
Net income[1]	212	99	218	105	169	111	100	82
Net income to common shareholder[1]	208	94	214	100	165	106	96	77

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Three months ended March 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities	240	287
Financing activities		
Long-term debt issued	300	1,000
Long-term debt retired	(250)	-
Short-term notes	-	(55)
Dividends paid	(42)	(14)
Investing activities		
Capital expenditures	(295)	(322)
Long-term investment[1]	-	(250)
Other financing and investing activities	3	7
Net change in cash and cash equivalents	(44)	653

[1] Represents $250 million of Province of Ontario Floating Rate Notes.

Operating Activities

Net cash from operating activities decreased by $47 million, or 16%, to $240 million compared to the same period last year. This change primarily reflects growth in accounts receivable balances in 2011 as a result of increases in revenue reflecting the two OEB decisions on distribution tariff rates. The decrease in cash from operating activities was partially offset by a

higher net income compared to the prior year, changes to certain regulatory accounts and increased taxes payable related to the implementation of the Harmonized Sales Tax that came into effect on July 1, 2010.

Financing Activities

Short-term liquidity is provided through funds from our operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holding of Province of Ontario Floating Rate Notes.

Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks and our holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. On March 28, 2011, we received commitment from all banks in the syndicate to extend the term of the $1,250 million credit facility from June 2013 to June 2014. The agreement to extend the term was executed on April 1, 2011.

At March 31, 2011, we had $7,825 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2011 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program until August 2011 is $3,000 million, of which $950 million was remaining and available as at March 31, 2011.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as of March 31, 2011.

In the first quarter of 2011, we issued $300 million in long-term debt under our MTN Program and repaid $250 million in maturing long-term debt. In the first quarter of 2010, we issued $1,000 million in long-term debt under our MTN Program and there were no debt maturities. In the first quarter of 2011, we did not issue any short-term notes and there were no short-term notes outstanding as at March 31, 2011. In the first quarter of 2010, we reduced our short-term notes by $55 million.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

In the first quarter of 2011, we paid common dividends of $38 million and preferred dividends of $4 million to the Province of Ontario (the Province). In the first quarter of 2010, we paid common dividends of $10 million and preferred dividends of $4 million.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities primarily represents capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest:

Three months ended March 31 (Canadian dollars in millions)	2011	2010	$ Change	% Change
Transmission	172	195	(23)	(12)
Distribution	123	126	(3)	(2)
Other	-	1	(1)	(100)
	295	322	(27)	(8)

Transmission

Our transmission capital expenditures decreased by $23 million, or 12%, in the first quarter to $172 million compared to the same period in 2010.

Expenditures to expand and reinforce our transmission system were $90 million, representing a decrease of $17 million compared to last year. The majority of these expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation. Significant investments were also made on load customer connection and local area supply projects to address growing loads. The reduction in expenditures compared to the prior year is primarily attributable to a number of multi-year inter-area network and local area supply projects that were substantially completed last year and put into service. These reductions in expenditures were partially offset by increased investments in a number of load customer connection projects.

Inter-area network upgrades with expenditures in the first quarter of 2011 included the Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. Also included was the installation of static var compensators (SVCs) at our Nanticoke and Detweiler transformer stations, which in the short term will support increased generation from the Bruce Nuclear facility and in the longer term, will enhance the transfer capability between Southwestern Ontario and the Greater Toronto Area. The impact of these investments was more than offset by lower expenditures associated with the completion in 2010 of the installation of capacitor banks in Southwestern Ontario. We also incurred lower expenditures associated with our Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which was put into service late last year. In addition, we are currently in the commissioning stages of installing an SVC at our Kirkland Lake Transformer Station as part of our project to install SVCs at our Porcupine and Kirkland Lake transformer stations, which will increase the North-South interface transfer capability to access available northern generation.

Local area supply project expenditures were also lower in the period as we completed two major projects in the first quarter of last year. This year, we are continuing to invest in our Woodstock Area Transmission Reinforcement Project, which will increase capacity to ensure supply reliability in the Woodstock area, and our Switchyard Reconstruction Project at our Burlington Transformer Station, which will increase the load supply capacity to ensure reliability of supply to customers in the area.

Expenditures to sustain our existing transmission system were $73 million, representing a decrease of $7 million compared to the same period in 2010. This reduction was primarily related to lower line requirements reflecting a lower demand for storm restoration expenditures. The decrease was also attributable to the timing of on-going expenditures to enhance security infrastructure related to the prevention of copper theft, scheduled to re-commence in the second quarter. Our other transmission capital expenditures were $9 million in the first quarter of 2011, representing a marginal increase of $1 million over the same period in the prior year.

Distribution

Our distribution capital expenditures decreased by $3 million, or 2%, to $123 million in the first quarter of 2011, compared to the same period of the prior year.

Capital expenditures to expand and reinforce our distribution network were $63 million, representing a reduction of $8 million compared to last year. We experienced reductions relating to smart meter installations having completed a significant number of residual meter installations in 2010. During the year, we continued to invest in our smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading

capability and integration with the IESO meter data repository. Out of our 1.3 million customers with meters installed as at March 31, 2011, we had over 862,000 consuming power based on time-of-use pricing. We also continued to invest in our Smart Grid Program which will enhance our operations and support distributed generation.

Expenditures to sustain our distribution system were $47 million, an increase of $1 million from the same period in the prior year. Sustainment program expenditures in the first quarter primarily include storm restoration work, wood pole replacements and work related to joint use and relocation of our lines. Our other distribution capital expenditures were $13 million in 2011, representing an increase of $4 million from last year.

Future Capital Expenditures

Our capital expenditures in 2011 are budgeted at approximately $1.8 billion. The 2011 capital budgets for our Transmission and Distribution businesses are about $1,050 million and $750 million, respectively. Under Canadian generally accepted accounting principles (GAAP), capital expenditures are expected to be approximately $1.9 billion in 2012 and approximately $1.8 billion in 2013. These expenditures reflect the sustainment requirements of our aging infrastructure, budgeted at approximately $550 million in 2011, $700 million in 2012 and $700 million in 2013. Development projects, including smart grid, inter-area network upgrades that reflect supply mix policies to phase out coal generation, local area supply requirements and requirements to enable distributed generation, are budgeted at approximately $950 million in 2011, $950 million in 2012 and $850 million in 2013. These development investments also reflect customer demand work, distributed generation connections and the rollout of smart grid. Other budgeted capital expenditures amount to approximately $300 million in 2011, $250 million in 2012 and $250 million in 2013. These expenditures include the replacement of our customer billing system to address end-of-life requirements and to further productivity realization from our entity-wide SAP platform.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work to advance specified transmission projects and upgrades to the system that will safely and reliably accommodate additional renewable energy. While our current budget does not include the estimated capital expenditures associated with these projects and upgrades to the system, they could be up to approximately $1 billion over a period to the in-service dates of these projects. On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licence amendment requires Hydro One Networks to develop and either seek approvals for or implement these projects.

In August 2010, the OEB introduced competition for transmission expansion projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansion under the OEB's competitive framework. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates (See Recent Developments). The items noted above will be considered in our upcoming budgeting process for the 2012 through 2014 period.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations under Canadian GAAP, as well as other major commercial commitments.

March 31, 2011 (Canadian dollars in millions)	**Total**	**2011**[1]	**2012/2013**	**2014/2015**	**After 2015**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	7,825	250	1,200	1,300	5,075
Long-term debt – interest payments	6,568	344	747	629	4,848
Inergi LP (Inergi) outsourcing agreement[2]	533	106	274	153	-
Operating lease commitments	54	4	15	8	27
Environmental and asset retirement obligations[3]	387	18	61	73	235
Total Contractual Obligations	15,367	722	2,297	2,163	10,185
Other Commercial Commitments *(by year of expiry)*					
Bank line[4]	1,250	-	1,250	-	-
Letters of credit[5]	114	113	1	-	-
Guarantees[5]	326	326	-	-	-
Pension[6]	271	109	162	-	-
Total Other Commercial Commitments	1,961	548	1,413	-	-

[1] The amounts disclosed represent the amounts due over the period April 1, 2011 to December 31, 2011.

[2] On May 1, 2010, we extended our Master Services Agreement with Inergi for a further three-year period. The term of the agreement, which would otherwise have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[3] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated material from our facilities and the decommissioning and removal of our switching station located at Ontario Power Generation's Abitibi Canyon Generating Station. The expenditure pattern reflects our planned work programs for the periods.

[4] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2013. On April 1, 2011 the term of this facility was extended from June 2013 to June 2014.

[5] We currently have outstanding bank letters of credit of $113 million relating to retirement compensation arrangements (RCAs). The other $1 million included in letters of credit pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[6] Contributions to the pension fund are made one month in arrears. Contributions for 2011 are based on an actuarial valuation filed in September 2010 and effective December 31, 2009. Our annual pension contributions for 2011 and 2012 will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we estimate our minimum pension contributions to be approximately $145 million in 2011 and $149 million in 2012 based on the expected level of pensionable earnings. Contributions for 2013 will be based on a new actuarial valuation effective December 31, 2012.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Statement of Operations or within our capital expenditures. Expenditures related to our environmental programs and asset retirement obligations are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation. In January 2010, we purchased $250 million of Province of Ontario Floating Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first three months of 2011, the deferred pension asset reported on our balance sheet decreased by $1 million to $459 million. We contributed $36 million into our pension plan and incurred $37 million in net periodic pension benefit cost. Contributions for 2011 and 2012 are based on an actuarial valuation effective December 31, 2009 that was filed in September of 2010. Based on current factors, we currently estimate our annual pension contributions to be approximately $145 million in 2011 and $149 million in 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, changes in benefits and actuarial assumptions.

Our pension plan experienced a positive return of 2.45% in the first quarter of this year. Consistent with other pension plans, our pension plan could be negatively impacted during the remainder of the year as a result of the current economic uncertainty and financial market volatility. However, our fund continues to recover and experience positive returns. The overall return for 2010 was approximately 9.96%.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011, with comparative data also reported under IFRS. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their adoption of IFRS for one year. Currently, we are working towards adopting IFRS for our fiscal year beginning on January 1, 2012.

In anticipation of the 2008 decision from the AcSB, we commenced our IFRS conversion project in 2007. The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high-level review and identification of the major differences between current GAAP and IFRS in all subject areas, resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our Company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all our policy analyses. We are currently engaged in the implementation phase which is the final phase of our project. We are tracking our comparative results under IFRS this year. Our teams continue to monitor progress relative to key milestones, monitor developments from both the International Accounting Standards Board (IASB) and the AcSB, update recommendations and develop financial reports. We continue to have ongoing dialogue with our external auditors about possible outcomes of our project.

We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries, and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as standards evolve.

Accounting Policies

The areas with the highest potential to significantly impact our Company upon conversion to IFRS are regulatory assets and liabilities, fixed-assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1).

Property, Plant and Equipment

On May 6, 2010, the IASB issued the omnibus *Improvements to IFRS*, which included an amendment to IFRS 1 applicable to entities with rate-regulated activities. It includes transition relief for first-time adopters by offering an optional exemption to use the carrying amount of fixed assets or intangible assets as deemed cost on the transition date when the carrying amount includes costs that would not otherwise qualify for capitalization. We will elect to use this exemption for our regulated businesses.

Regulatory Assets and Liabilities

Rate-regulated accounting (RRA) is not permitted under IFRS. RRA affects the timing of the accounting recognition of costs, revenues, losses and gains. The inability to recognize regulatory assets and liabilities after implementing IFRS in 2012 will impact our statement of operations by causing a change in the timing of recognition of such amounts. In the absence of RRA, the write-off of our regulatory assets and regulatory liabilities would have resulted in a net reduction to retained earnings of approximately $210 million as at January 1, 2011.

In the absence of a definitive plan for a new project to consider the issuance of a RRA standard by the IASB, we are evaluating the option of adopting United States Generally Accepted Accounting Principles (US GAAP) in lieu of IFRS. Our current application of Canadian GAAP for rate-regulated activities is generally consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on our financial statements will be assessed as part of the evaluation of this option. We continue to plan our transition to IFRS as we assess this alternative.

Construction and Development In-Progress

Current IFRS are significantly different from Canadian GAAP in terms of the expenditures that can be capitalized to in-progress construction and development programs and projects. Certain fixed asset and intangible asset expenditures are ineligible for capitalization under IFRS. In the absence of RRA, the estimated impact on our financial statements would have been a reduction of approximately $300 million in capital expenditures and an increase of approximately $300 million in operations, maintenance and administration expense had this accounting been followed in 2010. For 2012 rates, the OEB directed our Company to adopt this change in accounting classification for ineligible expenditures in determining the revenue requirement of our Transmission Business.

Employee Future Benefits

In the absence of RRA, the continuation of accounting for expenditures related to employer-sponsored pension plans on a cash basis is not permissible. Regulatory assets and liabilities, representing the cumulative difference between our Company's pension contributions currently accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP, would not meet the definition of assets or liabilities under IFRS and hence will require de-recognition at the IFRS transition date. We have assessed our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. The possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately to retained earnings upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits* (IAS 19). In the absence of rate-regulated accounting, we intend to recognize a retrospective adjustment for these amounts under IAS 19, without using the IFRS 1 exemption. The impact of adopting IAS 19 retrospectively at January 1, 2011 would have been a reduction to retained earnings of $319 million.

In April 2010, the IASB published an exposure draft, *Defined Benefit Plans (Proposed Amendments to IAS 19 Employee Benefits)*, with significant implications for both financial position and income reporting. Deferred recognition of actuarial gains and losses would be eliminated and instead all changes in the defined benefit obligation and in the fair value of plan assets would be recognized in the Statement of Comprehensive Income when those changes occur. The exposure draft also proposed a new presentation approach where the changes in the defined benefit obligation and the fair value of plan assets would be segregated and separately disclosed as service cost, finance cost and re-measurement adjustments. Service cost and finance cost components would be recognized in the Statement of Operations. The re-measurement adjustments representing actuarial gains and losses would be recognized as part of other comprehensive income. The proposals in the exposure draft have been substantially approved by the IASB and the revised standard incorporating the amendments is expected to be finalized in early 2011, with an effective date no earlier than 2013. Retrospective application will be required. The new accounting standard when adopted in 2013 or in later years will result in higher volatility in the Statement of Comprehensive Income due to the recognition of the full amount of actuarial gains and losses.

Payments in Lieu of Corporate Income Taxes

We recognize future tax assets and liabilities in accordance with the Canadian Institute of Chartered Accountants Handbook's section 3465, *Income Taxes*, which was amended effective January 1, 2009 to bridge the convergence to IFRS. As such, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. Without RRA, the impact on our provision for payments in lieu of corporate income taxes would be recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the provision for PILs for the year ended December 31, 2010 would have been higher by approximately $100 million including the impact of a change in substantively enacted tax rates.

OEB Consultation

On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

On February 24, 2010, the OEB issued a letter to all licensed electricity distributors and rate-regulated natural gas utilities for the purpose of clarifying the OEB's view released in July on accounting for overhead costs in the cost of new capital works effective January 1, 2011. The OEB stated in the letter that it would be requiring full compliance with IFRS requirements, including those in IAS 16, *Property, Plant and Equipment* (IAS 16), as applicable to non-regulated enterprises and only where the OEB authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable. We continue to assess this guidance in light of the AcSB's revised implementation date.

On November 8, 2010, the OEB published an amendment to a report it made on its policy, *Transition to International Financial Reporting Standards*. In response to the AcSB allowing rate-regulated entities the option to delay their adoption of IFRS to January 1, 2012, the OEB has adjusted certain policy statements in the report to account for this choice.

On November 17, 2010, the OEB initiated a working group to develop recommendations on how IFRS should be implemented in an incentive regulation mechanism (IRM) regime. On March 31, 2011, the OEB published a Staff discussion paper with proposed recommendations arising from this process for stakeholder comment. We actively participated in the OEB working group and have commented on the Staff discussion paper. The recommendations provide accounting, reporting and regulatory guidance for entities that implement IFRS while they are operating within an IRM regulatory environment. Several of the Staff recommendations also have relevance for entities that are adopting IFRS under a cost of service rate setting regime. In addition, the proposed recommendations include a proposal that the OEB will neither encourage nor prohibit the use of US GAAP as a basis for regulatory accounting and reporting where an entity has properly adopted US GAAP as its preferred basis of external reporting. Specific criteria for seeking OEB approval for the adoption of US GAAP as a basis for regulatory accounting and reporting are provided in the Staff paper.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We are continuously analyzing the impacts of changes on our disclosure controls and procedures and internal controls over financial reporting as we proceed through our implementation of IFRS. Additional disclosure controls may be required to address first-time adoption and additional internal controls may be required to implement changes in our accounting policies and to support our ongoing IFRS reporting requirements.

We have initiated the process of analyzing our current disclosure control and procedure and internal control documentation to identify changes required upon the adoption of IFRS. We have categorized each control process as low, medium or high-impact, based on the currently assessed risk of a major change being required upon implementation of IFRS. This ranking was completed in the fourth quarter of 2009. We completed updating the documentation for all of the low and medium-risk processes with IFRS implementation impact, including process documentation and risk and control matrices, during the second quarter of 2010. We initiated the revisions to our high-risk processes in the first quarter of 2011 and anticipate we will complete these revisions in the second quarter. Once our high-risk process documentation has been updated, we will begin walkthroughs of all of our revised process and control documentation for low, medium and high-risk processes. At this time we estimate that we will complete this on a timely basis for reporting under IFRS in 2012.

Financial Reporting Expertise

The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a quarterly basis, or more often as necessary.

Training has been provided to our Audit and Finance Committee and senior executive management to communicate the key differences between Canadian GAAP and IFRS, and to provide them with an overview of the key impacts conversion to IFRS could have on our financial statements. Our Audit and Finance Committee and senior management continue to be updated for key developments in IFRS and their potential impact on our financial statements. Updates are provided on at least a quarterly basis. This will continue through to our conversion to IFRS in 2012.

Training of key finance and operational staff commenced in 2007 and has been ongoing. During the third quarter of 2010, we continued to provide training to our key finance and operational staff. To date, they have been trained in many key areas including property, plant and equipment, regulatory accounting, revenue recognition, liabilities, employee benefits, financial instruments and most recently income taxes. In addition to sessions on specific topics, we have also held two financial reporting update sessions. During the remainder of this year, we will continue to provide IFRS financial reporting update sessions on a regular basis.

Due to the extensive staffing requirements associated with such a large-scale project, an external expert advisor was engaged to assist with our IFRS conversion project, from the planning phase through to implementation.

Business Activities

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Adoption of IFRS could change our results and impact our debt covenants. For example, covenants would be impacted as a result of de-recognition of regulatory assets and liabilities, accounting for expenditures related to employer-sponsored pension plans on an accrual basis versus a cash basis and the change in costs that are allowable versus disallowable for capitalization as part of the cost of self-constructed assets. As part of our IFRS transition project, we have been analyzing the impact of potential changes in accounting policy on our debt covenants and communicating potential scenarios and impact analyses to our Audit and Finance Committee. Based on our current estimates, we would remain in compliance with our debt covenants. However, we met with our financial institutions and amended our credit agreement with the syndicate of banks to consider the potential impacts that IFRS may have on our covenants. Specifically, the calculation of our debt to total capitalization ratio was modified under this agreement for certain items to factor in IFRS impacts, such that the debt to total capitalization ratio is representative of what it was prior to IFRS. The same ratio is used to support the indenture agreement with our bondholders. Given our current estimates, the indenture agreement was not updated at the same time because we anticipated remaining within the threshold for our debt to capitalization ratio. We have continued to monitor the impact of conversion on our debt covenants as IFRS develops and as we finalize our policy choices under IFRS. With the deferral of the IASB rate-regulated activities project, we continue to monitor the impact on our debt to capitalization ratio and identify appropriate next steps.

Information Technology (IT) Systems

As part of our entity-wide system improvement project, many of our major financial systems were replaced in 2008 and 2009. To ensure that the future requirements of IFRS would be met, common team members were included within the governance structure of our IFRS project and the new entity-wide system implementation team. At the same time, members of the IFRS implementation team were involved in the design of our new entity-wide system. IT implications were identified and assessed during our diagnostic and design and planning stages of our IFRS project and were incorporated in the project's solution development stage. For example, the new system has been configured to track depreciation on a component level, based on the useful life of the asset, as currently required under IAS 16. The new system has also been configured to track allowable versus disallowable costs for capitalization under IAS 16. The system was designed with maximum flexibility given the uncertainty of the outcome of impactive IASB projects. When we elected to defer implementation of IFRS for one year, we made the required changes to continue reporting under Canadian GAAP until January 1, 2012. We have substantially completed required changes to our systems in order to have them ready to report under IFRS beginning on January 1, 2012, with 2011 comparatives. We are currently tracking our 2011 results simultaneously under IFRS.

Environmental Reporting

We currently record environmental liabilities for the estimated future expenditures to comply with regulations that require us to remediate certain environmental issues. Specifically, we have obligations related to PCB-contaminated equipment and chemically-contaminated lands adjacent to certain of our properties. We also currently record an asset retirement obligation (ARO) for the removal and disposal of asbestos-containing materials from some of our buildings. These obligations are recorded based on the present value of the future estimated cash flows. Under Canadian GAAP this present value is calculated using a fixed discount rate which is the credit-adjusted risk-free rate at the date of liability recognition. The impact of this change on our recorded obligations cannot be predicted at this time as it will depend on future economic conditions.

Under Canadian GAAP, an ARO exists where there is a legal obligation to remove and dispose of an asset or remediate a contaminated site. Under IFRS, an ARO also includes obligations that are not legal but which are constructive in nature. Such a constructive obligation may be inferred from other factors such as a reporting enterprise's policies, actions or public statements. Under IFRS, new constructive obligations may be recorded as AROs in cases where we expect that specific lands

will no longer be used for operational purposes in perpetuity and where we expect to remove assets or remediate the properties.

Estimated Adjustments to Opening Shareholder's Equity on Adoption of IFRS as at January 1, 2011

The following table provides the equity section of the Canadian GAAP Consolidated Balance Sheet as at January 1, 2011 and the estimated IFRS adjustments as described above to arrive at the opening position under IFRS. Circumstances may arise, including changes in IFRS, regulations or economic conditions, which could change these adjustments. The main impacts on opening retained earnings are summarized as follows:

- A reduction in opening retained earnings of $210 million reflecting the de-recognition of net regulatory assets and liabilities in absence of RRA under IFRS.
- A reduction in opening retained earnings of $319 million for additional pension and other employee benefit obligations reflecting the accrual basis of accounting for cumulative actuarial gains and losses under *Employee Benefits* (IAS 19) assuming retrospective restatement. Further, the IASB issued an exposure draft, *Defined Benefit Plans*, in April 2010 that proposes fair value accounting for pensions by recognizing all actuarial gains and losses in the period in which they occur. The changes in the exposure draft have already been approved by the IASB and the revised standard incorporating the amendments is expected to be finalized in the middle of 2011 for adoption in 2013. The impact of adopting the new proposals retrospectively would be an additional reduction to opening January 1, 2011 retained earnings of $1,053 million.
- A re-classification of preferred shares of $323 million to liabilities, specifically long-term debt, under IFRS.
- A net reduction in shareholder's equity of about $852 million under current IAS 19. The reduction to shareholder's equity would be $1,905 million based on fair value accounting for pensions under revised IAS 19.

Canadian dollars in millions	**Canadian GAAP January 1, 2011**	**Regulatory Assets and Liabilities**	**Pension Benefits (IAS 19)**	**Preferred Shares**	**IFRS January 1, 2011**
Shareholder's equity:					
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	-	-	(323)	-
Common shares (authorized: unlimited; issued: 100,000)	3,314	-	-	-	3,314
Retained earnings	2,354	(210)	(319)	-	1,825
Accumulated other comprehensive income	(10)	-	-	-	(10)
Total shareholder's equity	**5,981**	**(210)**	**(319)**	**(323)**	**5,129**

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Our Supply Chain Enhancement Project to develop an operating framework that outlines the strategy and objectives of supply chain is expected to be implemented in the second quarter. The resulting new processes are currently being reviewed to assess the impact on the control environment. Process documents will be updated and controls will be tested for design and operating effectiveness throughout this year.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended March 31, 2011, together with other financial information included in our quarterly securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our Company is made known within our Company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

Transmission Licence Amendment and Shareholder Declaration and Resolution

On February 28, 2011, the OEB issued its Decision and Order to amend the transmission licence of our subsidiary, Hydro One Networks, to require it to work in co-operation with the OPA to establish the scope and timing of certain transmission projects for the purposes of accommodating the safe connection of renewable energy generation facilities, including increasing short circuit and/or transformer capacity at up to 15 of Hydro One Networks' transformer stations during a 48-month period commencing March 1, 2011. In a letter dated April 7, 2011, the OPA provided the initial list of 10 transformer stations for upgrading. The overall capital cost for the 10 stations is estimated to be approximately $50 million and the projected in-service dates range from August 2011 to June 2012.

In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and our Company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of our Company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investment and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendments made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement, internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within our Company, including the timing of any such decisions.

Collective Bargaining Agreements

On March 23, 2011, a tentative two-party settlement was reached between Hydro One and the Power Worker's Union (PWU) to finalize a new collective agreement. Our Board of Directors has approved the settlement. The PWU is seeking ratification of the settlement by its membership.

On April 5, 2011, the Canadian Auto Workers' membership ratified an agreement with our subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton). The agreement was approved by the Board of Directors of Hydro One Brampton on April 14, 2011.

Update on Major Projects

Bruce to Milton Transmission Reinforcement Project

On March 15, 2011, Hydro One Networks received approval from the OEB under section 99 of the *Ontario Energy Board Act* to continue acquiring the remaining property rights required to construct the line. However, Hydro One Networks' development permit is pending a decision from the Ministry of Natural Resources on a Niagara Escarpment Commission appeal hearing that concluded on April 6, 2010.

Vansickle Transformer Station Upgrade Project

Our Vansickle Transformer Station Upgrade Project was put into service in the first quarter of this year. The additional capacity provided by this project will provide increased reliability of service and address load growth in the St. Catharines area, including that required by a new hospital that is currently under construction.

Status of Rate Applications

Hydro One Brampton Networks

On April 4, 2011, the OEB issued its decision regarding the 2011 cost-of-service rate application made by our subsidiary Hydro One Brampton Networks. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters, effective May 1, 2011. The new rates result in a total bill increase for an average customer of approximately 0.5%.

Hydro One Remote Communities Inc. (Hydro One Remote Communities)

On March 28, 2011, the OEB issued its decision regarding the 2011 cost-of-service rate application made by our subsidiary Hydro One Remote Communities. The OEB approved the submission on the basis of its third-generation incentive regulation mechanism policies. The revised rates were approved with an effective date and implementation date of May 1, 2011. The new rates result in an increase of approximately 0.38% on an average residential customer's overall monthly bill.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

Three months ended March 31 (Canadian dollars in millions, except earnings per common share)	2011	2010
Net income	212	169
Net cash from operating activities	240	287
Capital expenditures	295	322
Earnings per common share	2,076	1,651
Earnings coverage ratio[1]	2.55	2.08
Net asset coverage on long-term debt[2]	1.79	1.77
Total debt to capitalization[3]	56%	57%

[1] The earnings coverage ratio has been presented for the twelve months ended March 31, 2011 and March 31, 2010, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2] The net asset coverage on long-term debt ratio has been presented as at March 31, 2011 and December 31, 2010 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] Total debt to capitalization ratio has been presented as at March 31, 2011 and December 31, 2010 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy related revenues and profit; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impact of new regulatory guidelines and impacts of decisions from the OEB and other governing bodies; statements related to the status of our rate applications and expected impacts on an average customer's bill; expectations regarding rate increases including the application of such increases and the benefit such increases may have on our system; statements regarding our future liquidity and capital resource and operating requirements; expectations regarding our financing activities; expectations regarding the results of our on-going and planned projects and/or initiatives and their completion dates; statements regarding future capital expenditures, budgets and our investment plans; statements related to smart meters and the associated smart grid; statements regarding contractual obligations and other commercial commitments; statements about our outsourcing arrangement with Inergi LP; statements regarding the amount and timing of future estimated environmental expenditures; statements regarding future pension contributions and our pension plan and actuarial valuation; statements about IFRS and IASB and their expected impacts, our conversion to IFRS, planned courses of action, and expected impacts in the event of a discontinuance of regulatory accounting; statements regarding US GAAP; and statements related to our debt covenants. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; satisfactory resolution of the issue of rate regulated accounting under IFRS; and no significant event occurring

outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to our memorandum of agreement with it;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- on-going discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements;
- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- investment returns, changes in benefits or actuarial assumptions;
- the risk associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- unanticipated changes in our costs;
- the potential for substantial and currently undetermined or underestimated environmental costs and liabilities or that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risk that the tentative collective agreement settlement may not be ratified by the members of the PWU;
- the risks associated with changes in interest rates;
- the risks associated with current economic uncertainty and financial market volatility;
- the impact of the GEA on our company and the costs and expenses arising there from; and
- the impact of increased competition on our transmission business.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2010 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at May 12, 2011. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

Three months ended March 31 (Canadian dollars in millions, except per share amounts)	2011	2010
Revenues		
Transmission	351	320
Distribution	1,093	983
Other	16	16
	1,460	1,319
Costs		
Purchased power	719	655
Operation, maintenance and administration	262	258
Depreciation and amortization	144	139
	1,125	1,052
Income before financing charges and provision for payments in lieu of corporate income taxes	335	267
Financing charges	84	85
Income before provision for payments in lieu of corporate income taxes	251	182
Provision for payments in lieu of corporate income taxes	39	13
Net income	212	169
Other comprehensive income	-	-
Comprehensive income	212	169
Basic and fully diluted earnings per common share *(Canadian dollars)*	2.076	1.651

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	2011	2010
Retained earnings, beginning of period	2,354	1,791
Net income	212	169
Dividends *(Note 3)*	(42)	(14)
Retained earnings, end of period	2,524	1,946

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

Three months ended March 31 (Canadian dollars in millions)	2011	2010
Accumulated other comprehensive income, beginning of period	(10)	(10)
Other comprehensive income	-	-
Accumulated other comprehensive income, end of period	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	March 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash	-	33
Short-term investments	154	139
Accounts receivable (net of allowance for doubtful accounts)	1,037	911
Regulatory assets	30	42
Materials and supplies	22	21
Future income tax assets	34	35
Other	11	8
	1,288	1,189
Fixed assets:		
Fixed assets in service	19,885	19,767
Less: accumulated depreciation	7,368	7,247
	12,517	12,520
Construction in progress	1,559	1,394
Future use land, components and spares	141	139
	14,217	14,053
Other long-term assets:		
Regulatory assets	1,051	1,013
Deferred pension asset	459	460
Long-term investment	250	249
Intangible assets (net of accumulated amortization)	196	197
Goodwill	133	133
Future income tax assets	19	19
Other	6	9
	2,114	2,080
Total assets	17,619	17,322

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	March 31, 2011	December 31, 2010
Liabilities		
Current liabilities:		
Bank indebtedness	26	-
Accounts payable and accrued charges	837	884
Regulatory liabilities	54	72
Accrued interest	121	84
Long-term debt payable within one year *(Note 4)*	250	500
	1,288	1,540
Long-term debt *(Note 4)*	7,570	7,278
Other long-term liabilities:		
Employee future benefits other than pension	997	980
Regulatory liabilities	569	540
Future income tax liabilities	732	693
Environmental liabilities	285	287
Asset retirement obligations	11	11
Long-term accounts payable and other liabilities	16	12
	2,610	2,523
Total liabilities	11,468	11,341
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,524	2,354
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	6,151	5,981
Total liabilities and shareholder's equity	17,619	17,322

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

Three months ended March 31 (Canadian dollars in millions)	**2011**	**2010**
Operating activities		
Net income	212	169
Environmental expenditures	(4)	(3)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	131	128
Regulatory asset and liability accounts	26	(3)
Future income taxes	2	9
Other	(1)	-
	366	300
Changes in non-cash balances related to operations	(126)	(13)
Net cash from operating activities	240	287
Financing activities		
Long-term debt issued	300	1,000
Long-term debt retired	(250)	-
Short-term notes payable	-	(55)
Dividends paid	(42)	(14)
Other	(2)	-
Net cash from financing activities	6	931
Investing activities		
Capital expenditures		
Fixed assets	(277)	(317)
Intangible assets	(18)	(5)
	(295)	(322)
Long-term investment	-	(250)
Other assets	5	7
Net cash used in investing activities	(290)	(565)
Net change in cash and cash equivalents	(44)	653
Cash and cash equivalents, beginning of period *(Note 6)*	172	(26)
Cash and cash equivalents, end of period	128	627

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles (GAAP) for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2010 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)

On February 13, 2008 the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On September 10, 2010, the AcSB decided to permit rate-regulated entities to defer their IFRS implementation date to January 1, 2012. As such, the Company will apply IFRS to its financial statements ending December 31, 2012 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2011, for comparative purposes. The Company continues to assess the impact of conversion to IFRS on its results of operations. In the absence of a definitive plan for a new project to consider the issuance of a rate-regulated accounting standard by the International Accounting Standards Board, Hydro One is evaluating the option of adopting United States (US) GAAP in lieu of IFRS. The Company's current application of Canadian GAAP for rate-regulated activities is generally consistent with US GAAP. Any differences between Canadian and US GAAP and their impact on the Company's financial statements will be assessed as part of the evaluation of this option. Hydro One continues to plan its transition to IFRS as it assesses this alternative.

3. DIVIDENDS

During the three months ended March 31, 2011, preferred dividends in the amount of $4 million (2010 - $4 million) and common dividends in the amount of $38 million (2010 - $10 million) were declared.

4. LONG-TERM DEBT

On January 19, 2011, Hydro One issued additional 2.95% notes with a principal amount of $250 million under its Medium-Term Note (MTN) Program. These notes, which mature on September 11, 2015, were an additional offering of notes originally issued on September 13, 2010 for $250 million. This additional issuance brings the total amount outstanding for this issue to $500 million.

Hydro One entered into two fixed-to-floating interest-rate swaps, effective on January 19, 2011, each with a $125 million notional principal amount, to convert the $250 million notes issued on the same day into three-month variable-rate debt. The Company designated these swaps as fair value hedges of interest rate risk. As such, changes in fair value are recognized in the Consolidated Statement of Operations for the period, as are changes in the fair value of the related fixed-rate notes. To the extent the hedge is ineffective, any ineffective amount is recorded immediately in financing charges within the Consolidated Statement of Operations. This amount was insignificant for the period.

On January 24, 2011, The Company issued $50 million in floating-rate notes under its MTN Program with a maturity date of July 24, 2015.

On March 22, 2011, the Company entered into five forward-rate agreements to lock-in five interest-rate resets on the floating rate it pays on $550 million of floating-rate debt, with respective settlement dates of: April 25, 2011; May 19, 2011; June 13, 2011; July 25, 2011; and August 19, 2011. These agreements were classified as held-for-trading financial instruments and are measured at fair value. As at March 31, 2011, the total fair value gain on the five agreements was approximately $58 thousand. This marked-to-market gain was recorded within financing charges in the first quarter.

5. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

Three months ended March 31 (Canadian dollars in millions)	2011	2010
Pension		
Net periodic benefit cost	37	45
Pension fund contribution	36	30
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	14	12
Charged to results of operations	22	18
Employee Future Benefits Other than Pension		
Net periodic benefit cost	27	22
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	11	9
Charged to results of operations	16	13

6. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash", "short-term investments" and "bank indebtedness."

7. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended March 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2011				
Segment profit				
Revenues	351	1,093	16	1,460
Purchased power	-	719	-	719
Operation, maintenance and administration	106	142	14	262
Depreciation and amortization	72	70	2	144
Income before financing charges and provision for payments in lieu of corporate income taxes	173	162	-	335
Financing charges				84
Income before provision for payments in lieu of corporate income taxes				251
Capital expenditures	172	123	-	295

Three months ended March 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	320	983	16	1,319
Purchased power	-	655	-	655
Operation, maintenance and administration	107	137	14	258
Depreciation and amortization	64	73	2	139
Income before financing charges and provision for payments in lieu of corporate income taxes	149	118	-	267
Financing charges				85
Income before provision for payments in lieu of corporate income taxes				182
Capital expenditures	195	126	1	322

(Canadian dollars in millions)	March 31, 2011	December 31, 2010
Total assets		
Transmission	9,937	9,805
Distribution	7,111	6,908
Other	571	609
	17,619	17,322

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

8. SUBSEQUENT EVENT

On February 28, 2011, the OEB issued its Decision and Order to amend the transmission licence of the Company's subsidiary, Hydro One Networks Inc. (Hydro One Networks) to require it to work in co-operation with the Ontario Power Authority (OPA) to establish the scope and timing of certain transmission projects for the purposes of accommodating the safe connection of renewable energy generation facilities, including increasing short circuit and/or transformer capacity at up to 15 of Hydro One Networks' transformer stations during a 48-month period commencing March 1, 2011. In a letter dated April 7, 2011, the OPA provided the initial list of 10 transformer stations for upgrading. The overall capital cost for the 10 stations is estimated to be approximately $50 million and the projected in-service dates range from August 2011 to June 2012.

In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the Shareholder) and the Company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. Specifically, the rights, powers and duties of the Company's Directors have been restricted with regard to any decisions regarding: the pursuit of cost recovery by Hydro One Networks from microFIT and small-scale (capacity allocation exempt) FIT generation projects or proponents thereof for costs related to investment and expenditures made, or required to be made, by Hydro One Networks in order to appropriately fund the upgrades at up to 15 transformer stations pursuant to the February 28, 2011 licence condition amendments made to Hydro One Networks' transmission licence; the pursuit of cost recovery by Hydro One Networks of such costs through regulatory processes designed to ultimately recover costs from Ontario electricity consumers through electricity rates; and whether or not to pursue and implement, internal cost recovery or cost mitigation measures designed to offset the costs associated with the upgrades, and to pursue further cost minimization strategies and to increase overall cost efficiencies within the Company, including the timing of any such decisions.

9. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the March 31, 2011 Consolidated Financial Statements.